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Direct Testimony
Farah L. Mandich

**STATE OF NORTH DAKOTA**
**BEFORE THE**
**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for the Acquisition of the 120 MW Northern Wind Facility

Case No. PU-21-____
Exhibit___(FLM-1)

**Resource Planning**

March 2, 2021

3 PU-21-93 Filed 03/02/2021 Pages: 53
Prefiled Direct Testimony of Farah Mandich
Northern States Power Company

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# I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Farah L. Mandich. I am a Specialist, Resource Planning for Northern States Power Company-Minnesota (NSP or Xcel Energy or the Company). The Company provides electric service to customers in Minnesota, North Dakota, and South Dakota (collectively the NSPM States). The Company's affiliate, Northern States Power, a Wisconsin corporation (NSPW), provides electric service to customers in Wisconsin and Michigan. The Company and NSPW, together under the Interchange Agreement, own and operate the five-state integrated NSP System.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since April 2019 in the areas of Regulatory Affairs and Resource Planning. I have been in my current position since October 2020. In my first role with the Company, in the Regulatory Affairs department, I worked with cross-functional teams to develop Integrated Resource Plan and resource acquisition filings for NSP.

Prior to joining Xcel Energy, I worked as a Policy Advisor for Southern California Edison, a large investor owned utility in California. In this role, I supported development of Integrated Resource Planning and resource acquisition regulatory filings before the California Public Utilities Commission. My statement of qualifications is provided as Exhibit___(FLM-1), Schedule 1.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I work within the Resource Planning team on the development of resource plans and acquisitions for the five-state integrated Upper Midwest Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. This includes assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the economic impacts of the Company's proposed acquisition of the repowered and expanded 120 megawatt (MW) Northern Winds project. My testimony supports the conclusion that the North Dakota Public Service Commission (Commission) should grant an advance determination of prudence (ADP) for the proposed resource acquisition. My testimony provides an economic analysis of the proposed acquisition and the overall ratepayer benefits it generates.

## II. ECONOMIC ANALYSIS

Q. HOW DID THE COMPANY EVALUATE THE ECONOMIC IMPACT OF THE PROPOSED NORTHERN WIND ACQUISITION?

A. The Company performed two economic analyses to evaluate the present value of revenue requirements (PVRR) impacts of the acquisition of the repowered and expanded Northern Wind project: (1) a "pro forma" spreadsheet analysis, and (2) a traditional analysis using EnCompass.

### A. Pro Forma Analysis

Q. WHAT IS A PRO FORMA ANALYSIS?

A. A pro forma is a spreadsheet analysis which uses project cost and production information, along with the Company's financial assumptions, to evaluate the present value and annual cost implications of a proposed acquisition. Specifically, the pro forma compares the expected costs of the Project to a baseline where the existing PPAs remain in our portfolio until the end if their terms and generic wind generation equivalent to the expected output of the Northern Wind Project is added thereafter. Further, in recognition of Advocacy Staff's request in the Mower County Wind ADP proceeding (Case No. PU-19-310), we also performed a pro forma analysis in which we compared the Project to a baseline where the cost of replacement energy is represented by market prices.

Q. WHAT WERE THE RESULTS OF THE PRO FORMA ANALYSIS?

A. Our pro forma analysis showed that the Project would be expected to result in $30.2 million of customer savings over its lifetime, as compared to generic wind replacement. These savings are on a PVRR basis and do not include carbon dioxide costs, other environmental externality values, or costs for potential future carbon emissions regulations.

Q. WHAT WERE THE RESULTS OF THE PRO FORMA ANALYSIS USING MARKET ENERGY AS A REPLACEMENT FOR THE EXISTING PPAS?

A. Our pro forma analysis of the Project as compared to market price energy replacement after the current PPAs expire showed that the Project would result in an estimated $1.4 million of customer savings over its lifetime. Market price assumptions in this analysis were aligned with those used in our current resource planning process filed with the Commission in Case No. PU-19-220.

Q. WHAT DO THE RESULTS OF THE PRO FORMA ANALYSIS INDICATE?

A. The results of our pro forma analysis indicate that the Project is expected to provide cost savings to the Company's customers on a standalone basis, regardless of whether the existing PPAs are assumed to be replaced with generic wind resources or market energy. With this in mind, the Company conducted full resource planning modeling of the proposed Project using the EnCompass tool.

**B. Encompass Analysis**

Q. WHAT IS ENCOMPASS?

A. EnCompass is a capacity expansion and production cost modeling tool that allows the Company to optimize resource expansion plans based on a set of assumptions. Like Strategist, our previously-used resource planning model, EnCompass simulates the operation of the NSP System and estimates the total cost of energy over the life of the project on a present value basis. However, one of the primary differences between EnCompass and Strategist is that Encompass evaluates resource needs and cost on a chronological hourly basis, which better accounts for hourly variations on our system. The Company has largely shifted to using the EnCompass tool rather than Strategist to perform resource planning modeling because, as we add more variable resources to our system, it becomes increasingly important to ensure we are appropriately considering resource needs on an hourly basis.

Q. HOW DID THE COMPANY USE ENCOMPASS TO ANALYZE THE PROPOSED NORTHERN WIND ACQUISITION?

A. For this analysis, the Company simulated the operation of the NSP System through 2045, with and without the acquisition of the 120 MW Northern Wind facility, under a range of different assumptions. The Company's analysis assumes the addition of the four wind repowering projects described in the Company's pending ADP application in Case No. PU-20-425, as well as one under 50 MW repowering project for which the Company did not seek an ADP. The Company had initially selected a total of seven repowering projects, but negotiations have ceased for two of the small PPA projects for which the Company did not seek an ADP.

Q. WHY DID THE COMPANY'S MODELING USE THE ASSUMPTION THAT THE OTHER WIND REPOWERING PROJECTS WOULD BE ADDED TO THE SYSTEM?

A. As I noted in my Direct Testimony in Case No. PU-20-425, the Company conducted a portfolio analysis of the repowering proposals that were initially shortlisted to validate that the full portfolio of repowering projects would yield customer benefits. Because the Company considers the Northern Wind project as part of its overall current repowering portfolio proposal and in order to determine if the Northern Wind project would have incremental benefits in addition to the other repowering projects, we analyzed the customer impacts of the Northern Wind project in the context of the other repowering projects that have already been proposed.

Q. WHAT MODELLING INPUTS AND ASSUMPTIONS WERE USED IN THE ENCOMPASS MODELLING?

A. We evaluated the Northern Wind project's economic impact to our system using the same modeling assumptions as we used in Case No. PU-20-425, but as noted above we updated the Base Case to include the four wind repowering projects described in the Company's application in that case and one additional under 50 MW repowering project which was not included in that application. The full list of EnCompass modeling assumptions used in the Company's analysis is provided as Schedule 2 to my Direct Testimony.

This Base Case is compared with a Change Case in which the existing Chanarambie and Viking PPAs are removed from our portfolio and replaced with the repowered and expanded Northern Wind project. This allows us to examine whether the proposal will result in customer savings in the context of our full NSP System.

Q. WHAT WERE THE RESULTS OF THE ENCOMPASS ANALYSIS?

A. The results of our EnCompass analysis show that under our base assumptions, the acquisition of the repowered and expanded Northern Wind project results in net benefits of $54 million on a PVRR basis over the 2020-2045 analysis period. These cost savings do not include carbon dioxide costs, other externality values, or potential future regulatory costs for carbon emissions.

Q. DID THE COMPANY TEST THE IMPACT OF THE PROJECT UNDER OTHER SENSITIVITIES?

A. Yes. We also tested the impact of the Northern Wind project under sensitivity analyses for high and low gas, coal, and market prices. The full results of our Encompass analyses are included in Table 1 below. Our analysis indicates that the Project is expected to result in benefits to customers under all fuel sensitivities examined.

**Table 1: Savings Associated with the Addition of the Northern Wind Project, Relative to the Base Case**

| Cost sensitivity | Cost/(Savings) $2020 millions |
|---|---|
| Base PVRR | ($54) |
| Low Gas, Coal and Market Prices PVRR | ($62) |
| High Gas, Coal, and Market Prices PVRR | ($39) |

Q. IN GENERAL, WHAT IS THE SOURCE OF THE SAVINGS ASSOCIATED WITH THE NORTHERN WIND ACQUISITION?

A. Our modeling efforts show that we expect there to be fuel savings – offsetting generation from higher cost resources on our system – as a result of acquiring this Project. The analysis also shows benefits associated with the potential for this Project to defer future capacity additions, as discussed later in my testimony. Finally, the benefits reflect the value of Production Tax Credits (PTCs) and associated impacts to the Company's tax position, to the benefit of customers.

Q. WHY ARE THE SAVINGS PROJECTED BY THE ENCOMPASS MODELLING EFFORTS DIFFERENT THAN THE ESTIMATED SAVINGS UNDER THE PRO FORMA ANALYSIS?

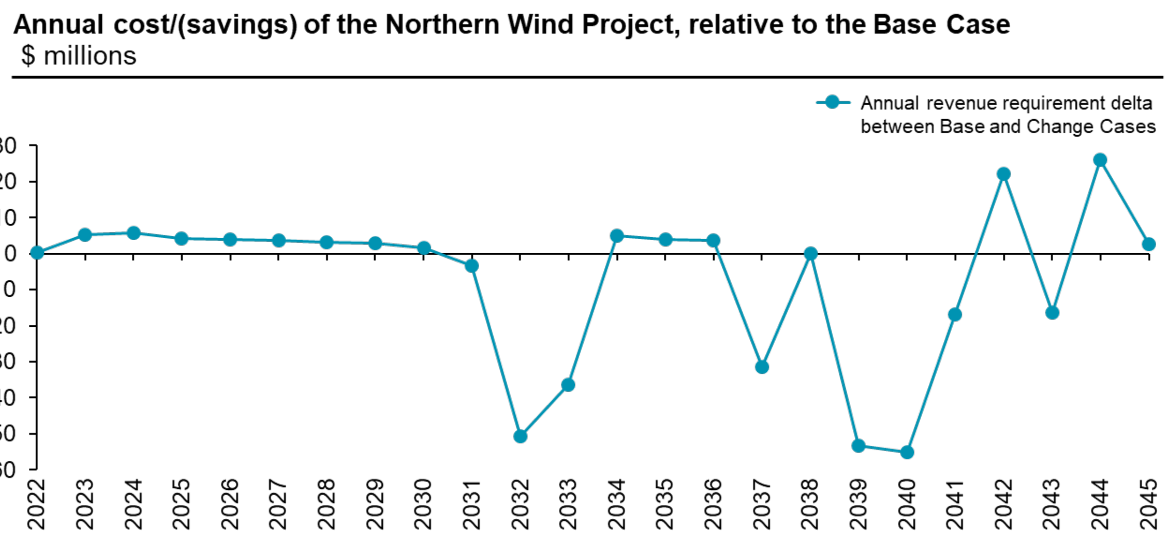
A. The pro forma model and EnCompass modeling represent two different approaches to examining potential customer benefits or costs attributable to the proposed project. The pro forma model shows us the expected revenue requirements of the Project as compared to one single alternative for an equivalent amount of replacement energy; here, either new generic wind or market energy. In EnCompass, we analyze the project within the context of our full Upper Midwest system, where the Encompass model analyzes system resource options and selects an optimal future capacity expansion plan and estimated dispatch patterns in a case with the Project included – what we call the "Change Case" – as compared to a "Base Case" without the Project included. In that way, the EnCompass analysis allows us to more dynamically examine a broader range of potential impacts based on our input assumptions. For example, the difference between the Base Case and Change Case in EnCompass helps us examine whether the addition of this Project could displace existing fuel sources or market interactions, or result in deferral of other capacity additions. In either case, however, the difference between the Base Case and the Change Case is a helpful way to examine whether we would expect customer benefits to result from the acquisition of the Project. Because both our pro forma analyses and our EnCompass analyses indicate that there will be cost savings from the Project, our confidence level that some amount of savings will accrue to customers in the long term is high.

### C. Annual Impacts

Q. DID THE COMPANY ANALYZE HOW THE COST SAVINGS FROM THE NORTHERN WIND ACQUISITION EVOLVE OVER THE LIFE OF THE PROJECT?

A. Yes. To understand how the potential costs or savings associated with the Northern Wind acquisition accrue over time, we examined total system costs on an annual basis. Figure 1 below portrays the annual (undiscounted) system cost impacts of the Base Case compared to a scenario in which the repowered and expanded Northern Wind project is added to our system.

**Figure 1: Annual Costs/(Savings) of Northern Wind vs. the Base Case**




Q. WHAT ACCOUNTS FOR THE FLUCTUATION IN CUSTOMER COSTS AND SAVINGS OF THE NORTHERN WIND REPOWERING RELATIVE TO THE BASE CASE OVER THE ANALYSIS PERIOD?

A. The fluctuation in the annual revenue requirement delta shown in Figure 1 is caused in part by Project-specific impacts such as the impact of deferred tax assets in the early 2030s. It is also the result of the Change Case shifting –

either forward or back – the year in which the capacity expansion model selects additional future generic resources to serve our customer load. The shifting in resource additions in particular leads to some of the year over year cost fluctuations in light of the types of generating units that our assumptions provide as options for the modelling algorithm to select to optimize the system. We currently use large generic units in our modeling to maintain continuity with legacy modeling utilizing the Strategist resource planning tool.

Q. WHAT IS THE CAUSE OF THE DECREASE IN SYSTEM COSTS RELATIVE TO THE BASE CASE IN 2032?

A. The annualized savings for 2032 relative to the Base Case are the result of two key factors. First, the estimated revenue requirement for the Northern Wind Project drops substantially in the 2031-2032 timeframe due to the impacts of the PTCs generated by the Project on the Company's tax position. Second, the overall expansion plan in the Change Case indicates that the Project delays generic resource additions in 2032 by one wind unit (equating to 750 MW of wind) for two years. The drop in cost reflects both the avoided capital cost of that wind unit in 2032 and other associated costs (such as assumed integration costs), outweighing any other factors that put upward pressure on costs in that year.

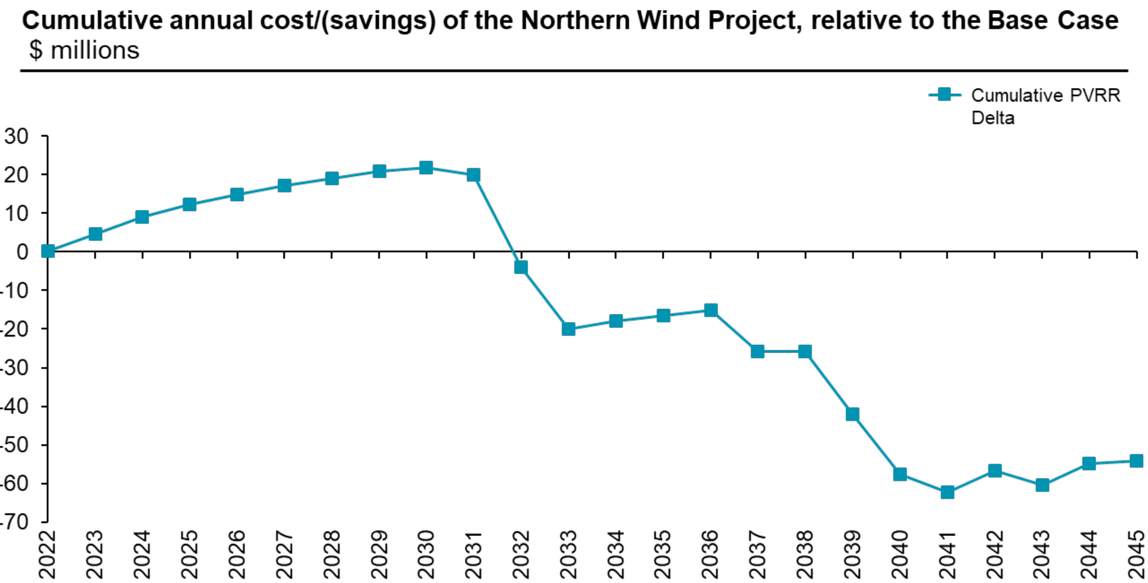
Q. WHAT ACCOUNTS FOR THE FLUCTUATIONS SHOWN IN FIGURE 1 IN 2037 AND AFTER?

A. The relative cost of the Change Case to the Base Case begins to fluctuate again in 2037 and beyond due in part to deferred or pulled-forward generic additions to the NSP System. In 2037, the model defers a combustion turbine (CT) addition. In 2038, the cost of the Change Case increases slightly due to a battery storage resource being pulled forward in the model. In the 2039-2040 timeframe, the costs of additional CTs are partially offset by deferred wind additions. Beyond 2040, similar fluctuations in the sets of resources added or deferred in a given year result in cost spikes up or down through the end of the analysis period in 2045.

Q. DOES THE NORTHERN WIND PROJECT MERELY GENERATE FLUCTUATIONS IN REVENUE REQUIREMENT OR DOES IT GENERATE NET SAVINGS?

A. As I noted earlier, the addition of the Northern Wind project generates net benefits of between $39 million and $62 million PVRR over the 2020-2045 analysis period. Figure 2 below shows the cumulative savings generated by the Northern Wind acquisition over time under our base assumptions, which generates $54 million in savings on a PVRR basis. Figure 2 indicates that the fluctuations in the annual revenue requirement of the Change Case relative to the Base Case do not negate the overall savings generated.

**Figure 2: Cumulative Cost/(Savings) of Northern Wind vs the Base Case**




Q. WHAT DOES FIGURE 2 SHOW?

A. Figure 2 shows that modest incremental costs accrued in the near term are expected to be offset fully by the early 2030s and subsequently, none of the year over year spikes in cost are large enough in magnitude to reverse this cumulative savings picture. These savings are generated by tax benefits, deferral of future capacity additions, and replacement of higher-cost fuel sources on the NSP System with Northern Wind.

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. I conclude that the Northern Wind acquisition will provide material cost savings to the NSP System when considered as part of the Company's broader portfolio of wind repowering projects as proposed in Case No. PU-20-425.

Q. HISTORICALLY, THE COMPANY HAS PROVIDED A RATE IMPACT ANALYSIS WITH ITS ADP APPLICATIONS. WHY WAS SUCH AN ANALYSIS NOT INCLUDED WITH THIS APPLICATION?

A. The Company's EnCompass modelling indicates that the Northern Wind acquisition will reduce costs and result in customer savings. Accordingly, we concluded that a rate impact analysis was not necessary. However, if the Commission desires such an analysis, we would be happy to provide one during discovery.

## III. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The Company's proposed acquisition of the repowered and expanded Northern Wind project is prudent. Our economic analysis showed that the acquisition will provide substantial cost saving benefits for customers as part of the Company's broader repowering portfolio. Specifically, we estimate that the Northern Wind acquisition will save customers approximately $54 million on a PVRR basis. Thus, the proposed acquisition is prudent and reasonable, and the Commission should grant an ADP.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF NORTH DAKOTA**

NORTHERN STATES POWER COMPANY
ADVANCE PRUDENCE – ACQUISITION OF
ACQUISITION OF 120 MW NORTHERN WIND FACILITY

CASE NO. PU-21-___

VERIFICATION

STATE OF MINNESOTA )
) SS.
COUNTY OF HENNEPIN )

Farah L. Mandich, being first duly sworn on oath, deposes and says that she is a Specialist, Resource Planning for Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony submitted in the above-captioned matter under her name was prepared under her direction, that she knows the contents thereof, and that the same is true and correct to the best of her knowledge and belief.

Farah L. Mandich

Subscribed and sworn to before me on this 26 day of February, 2021

STEVEN DELMONT SPIESS
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2025

Steven D. Spiess

Notary Public
My Commission expires: January 31, 2025

## Schedule 1
## Farah L. Mandich
## Statement of Qualifications

Farah Ladan Mandich is a Specialist, Resource Planning for Northern States Power Company – Minnesota. She currently works within the Company's Resource Planning team on the development of resource plans and acquisitions for the NSP System, which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. Mandich joined Xcel Energy in April 2019 as a Regulatory Policy Specialist, where she was responsible for developing resource planning and resource acquisition regulatory filings for NSP-M.

Prior to joining Xcel Energy, Mandich was a Policy Advisor at Southern California Edison (SCE), a large investor owned utility in California. In this role, she supported development of Integrated Resource Planning and resource acquisition regulatory filings before the California Public Utilities Commission. Before working on California regulatory issues, Mandich was a Knowledge Specialist in global consultancy McKinsey & Company's Electric Power & Natural Gas practice, where she served as a subject matter expert to both US and international clients on North American renewable energy markets.

Mandich received her Bachelor of Science in Economics from Texas Christian University and her Master of Public Policy from the University of Michigan's Gerald R. Ford School of Public Policy.

## MODELING ASSUMPTIONS AND INPUTS

Since filing our initial Resource Plan in July 2019 in Case No. PU-19-220, the Company has made several changes to its modeling approaches, inputs, and assumptions for the purposes of developing our Supplement Preferred Plan.

| Topic | Assumption | Change from Initial IRP Filing |
|---|---|---|
| *Modeling constraints* | | |
| Carbon emissions constraint | ▪ No constraint; baseload scenarios may not meet 80 percent reduction goal | ▪ Removed modeling constraint of 80 percent carbon reduction by 2030 |
| "No Going Back" wind replacement capacity | ▪ No assumption that existing wind will be replaced when plants or contracts reach end of life | ▪ Removed wind replacement capacity from baseline modeling |
| Reliability Requirement | ▪ Modeling does not include 5.7 GW firm, dispatchable capacity floor; model optimizes resources to develop expansion plans | ▪ Removed reliability requirement from baseline modeling |

| Topic | Assumption | Change from Initial IRP Filing |
|---|---|---|
| Near term wind availability constraint | ▪ No generic wind option made available for model to select before 2026 | ▪ Generic wind available to select in modeling for each year |
| Market sales limit | ▪ Limits market sales to 25 percent of retail load in EnCompass modeling | ▪ Not applicable; no market sales limit capability in Strategist |
| ***Market and technology assumptions*** | | |
| Market hourly price shaping | ▪ Shaped hourly market prices based on retail load | ▪ Hourly market price shaped based on thermal load |
| Fuel price forecasts | ▪ Updated to Fall 2019 forecast vintage | ▪ Changed from vintage available prior to previous filing |
| Technology price forecasts for wind, solar, and storage | ▪ Used National Renewable Energy Labs (NREL) *Annual Technology Baseline (ATB) 2019* assumptions | ▪ Updated from 2018 ATB to 2019 ATB for wind and solar<br>▪ Shifted from using internal price assumptions to 2019 ATB for storage |

| Topic | Assumption | Change from Initial IRP Filing |
|---|---|---|
| Wind resource production | ▪ Used 2019 NREL ATB price inputs for Technology Resource Group (TRG) 2 | ▪ Previously used 2018 ATB price assumptions for TRG 1, which reflected a higher capacity factor expectation |
| Solar resource production | ▪ Assumed 22 percent capacity factor in first year, with 0.5 percent per year degradation | ▪ Previously assumed 17.7 percent levelized capacity factor |
| Renewable transmission interconnect cost | ▪ Wind: $500/kW<br>▪ Solar: $200/kW | ▪ Wind: Increased from $400/kW for greenfield wind<br>▪ Solar: Increased from $140/kW |
| Solar capacity accreditation | ▪ 50 percent ELCC to 2023, declining to 30 percent in 2033 at a rate of 2 percent per year | ▪ 50 percent ELCC for the full analysis period |

| Topic | Assumption | Change from Initial IRP Filing |
|---|---|---|
| Wind capacity accreditation | ▪ 16.7 percent ELCC throughout the planning period | ▪ 15.6 percent ELCC throughout the planning period |
| Effective Reserve Margin | ▪ Reserve margin updated to 3.46 percent, based on latest MISO LOLE Study (2020-2021) | ▪ 2.98 percent effective reserve margin |
| *Upper Midwest System Assumptions* | | |
| Unit retirement dates | ▪ All existing unit retirement years with end of financial life | ▪ Selected units used differing retirement dates for resource planning purposes |
| Seasonal coal dispatch | ▪ King and Sherco 2 do not dispatch from March-May and September-November, through 2023 | ▪ No units were modeled with seasonal dispatch |
| Load forecasts | ▪ Updated to fall 2019 internal forecast vintage | ▪ Changed from fall 2018 internal forecast |

| Topic | Assumption | Change from Initial IRP Filing |
|---|---|---|
| DER forecasts | ▪ Updated to latest vintage for each technology | ▪ Changed from vintage available prior to previous filing |
| EV adoption forecasts | ▪ Updated to latest vintage, aligned with most recent forecasts used in IDP | ▪ Changed from vintage available prior to previous filing |
| Nuclear budgets | ▪ Updated to most recent vintage for Nuclear Decommissioning Trust, Operations and Maintenance and Capital Expenditure budgets | ▪ Changed from vintage available prior to previous filing |

In addition to these modifications for the IRP Supplement, we have made several additional model updates for the instant docket, to account for inclusion of resources that have been recently approved by the North Dakota Public Service Commission (NDPSC) and/or Minnesota Public Utilities Commission (MPUC). These changes are consistent with those made for the Company's filing in Case No. PU-20-425, and they include:

- Adjusting the Mower County Wind resource to reflect both the ND PSC and MPUC approval of our repowering and purchase proposal;[1]
- The addition of a 100 MW Deuel Harvest Wind and 80 MW Elk Creek Solar PPAs that support our Minnesota Renewable*Connect program expansion (the costs of which will recovered directly from participating customers in Minnesota);
- Updating baseline revenue requirement assumptions for the four Company-owned wind projects considered in this proposal;

[1] Per Case No. PU-19-310.

- Updating baseline cost and operational assumptions for the third-party wind projects proposed; and
- Updating how we model curtailments; whereas we previously only assigned energy costs to generation net of curtailment, we now also account for costs of energy that is ultimately curtailed.

Further, for the purposes of modeling the costs and benefits of the Northern Wind Project, the Company has further incorporated into the Base Case the four wind projects for which we submitted an Application for Advance Determination of Prudence in Case No. PU-20-425. These Projects, as well as one other PPA under 50 MW, were approved by the Minnesota Public Utilities Commission in Docket No. E002/M-20-620 on January 21, 2021.

As a result of these updates, the Base Case expansion plan used as a comparison point for assessing the Northern Wind project's economic costs/benefits is slightly altered relative to the IRP's Supplement Preferred Plan and the Wind Repower Base used in Case No. PU-20-425. The Base Case expansion plan used in modeling for this Application is detailed below.

## Northern Wind Application Base Case

| **Wind Repower Base Case (MW)** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Battery | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Firm Peaking | - | - | - | - | - | - | - | - | - | - | 374 | 748 | 374 | 748 | 374 |
| CC | - | - | - | - | - | - | - | 835 | - | - | - | - | - | - | - |
| Wind | - | - | - | - | - | - | - | - | - | - | - | - | 750 | 750 | 750 |
| Solar | - | - | - | - | - | 500 | 500 | - | - | 1,500 | 500 | - | - | - | - |
| DR | 33 | 132 | 67 | 62 | 47 | 41 | 12 | 14 | 15 | 17 | 19 | 20 | 21 | 22 | 24 |
| EE | 115 | 130 | 116 | 133 | 143 | 145 | 154 | 157 | 155 | 140 | 138 | 136 | 129 | 126 | 126 |
| Distributed Solar | 173 | 72 | 87 | 68 | 25 | 16 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **TOTAL** | **321** | **334** | **269** | **263** | **214** | **702** | **681** | **1,022** | **185** | **1,672** | **1,045** | **919** | **1,145** | **1,520** | **1,145** |

## A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.47 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction's last allowed/settled electric retail rate case.

**Table IV-1: Discount Rate and Capital Structure[2]**

| Discount Rate and Capital Structure | | | | |
|---|---|---|---|---|
| | Capital Structure | Allowed Return | Before Tax Electric WACC | After Tax Electric WACC |
| Long-Term Debt | 45.72% | 4.79% | 2.19% | 1.58% |
| Common Equity | 52.39% | 9.25% | 4.85% | 4.85% |
| Short-Term Debt | 1.89% | 3.55% | 0.07% | 0.05% |
| **Total** | | | **7.10%** | **6.47%** |

## B. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2 percent is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

## C. Reserve Margin

The reserve margin at the time of MISO's peak is 8.9 percent from the 2020-2021 LOLE Study Report, published November 2019. The coincidence factor between the NSP System and MISO system peak is 95 percent. Therefore, the effective reserve margin is:

$$(95\,percent\ coincidence\ factor) x\ (1 + 8.9\,percent) - 1$$
$$= \mathbf{3.46}\ percent\ effective\ reserve\ margin\ for\ NSP$$

## D. $CO_2$ Costs

The Present Value of Societal Cost (PVSC) Base Case $CO_2$ values are based on the high environmental cost values for $CO_2$ through 2024 (page 31 of the Minnesota

[2] Note: the Tables in this Schedule retain their numbering from our most recent Integrated Resource Plan.

Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 Gross Domestic Product Implicit Price Deflator (GDPIPD) of 113.416 and then escalated at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No. E999/CI-07-1199 and E999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.

The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

## Table IV-2: $CO_2$ Costs

| CO2 Costs ($ per short ton) | | | | | | |
|---|---|---|---|---|---|---|
| Year | Low Environmental Cost | High Environmental Cost | Low Environmental/ Regulatory Costs | Mid Environmental/ Regulatory Costs | PVSC - High Environmental/ Regulatory Costs | PVRR - Omitting CO2 Cost Considerations |
| 2018 | $9.09 | $42.76 | $9.09 | $25.92 | $42.76 | $0.00 |
| 2019 | $9.49 | $44.58 | $9.49 | $27.04 | $44.58 | $0.00 |
| 2020 | $9.90 | $46.45 | $9.90 | $28.18 | $46.45 | $0.00 |
| 2021 | $10.32 | $48.39 | $10.32 | $29.35 | $48.39 | $0.00 |
| 2022 | $10.77 | $50.38 | $10.77 | $30.57 | $50.38 | $0.00 |
| 2023 | $11.22 | $52.43 | $11.22 | $31.82 | $52.43 | $0.00 |
| 2024 | $11.69 | $54.55 | $11.69 | $33.12 | $54.55 | $0.00 |
| 2025 | $12.16 | $56.72 | $5.00 | $15.00 | $25.00 | $0.00 |
| 2026 | $12.67 | $58.97 | $5.10 | $15.30 | $25.50 | $0.00 |
| 2027 | $13.17 | $61.29 | $5.20 | $15.61 | $26.01 | $0.00 |
| 2028 | $13.70 | $63.67 | $5.31 | $15.92 | $26.53 | $0.00 |
| 2029 | $14.24 | $66.12 | $5.41 | $16.24 | $27.06 | $0.00 |
| 2030 | $14.80 | $68.64 | $5.52 | $16.56 | $27.60 | $0.00 |
| 2031 | $15.37 | $71.24 | $5.63 | $16.89 | $28.15 | $0.00 |
| 2032 | $15.97 | $73.91 | $5.74 | $17.23 | $28.72 | $0.00 |
| 2033 | $16.57 | $76.67 | $5.86 | $17.57 | $29.29 | $0.00 |
| 2034 | $17.21 | $79.50 | $5.98 | $17.93 | $29.88 | $0.00 |
| 2035 | $17.85 | $82.41 | $6.09 | $18.28 | $30.47 | $0.00 |
| 2036 | $18.52 | $85.41 | $6.22 | $18.65 | $31.08 | $0.00 |
| 2037 | $19.20 | $88.50 | $6.34 | $19.02 | $31.71 | $0.00 |
| 2038 | $19.91 | $91.68 | $6.47 | $19.40 | $32.34 | $0.00 |
| 2039 | $20.62 | $94.96 | $6.60 | $19.79 | $32.99 | $0.00 |
| 2040 | $21.38 | $98.32 | $6.73 | $20.19 | $33.65 | $0.00 |
| 2041 | $22.14 | $101.78 | $6.86 | $20.59 | $34.32 | $0.00 |
| 2042 | $22.94 | $105.34 | $7.00 | $21.00 | $35.01 | $0.00 |
| 2043 | $23.74 | $109.00 | $7.14 | $21.42 | $35.71 | $0.00 |
| 2044 | $24.58 | $112.76 | $7.28 | $21.85 | $36.42 | $0.00 |
| 2045 | $25.43 | $116.63 | $7.43 | $22.29 | $37.15 | $0.00 |
| 2046 | $26.33 | $120.61 | $7.58 | $22.73 | $37.89 | $0.00 |
| 2047 | $27.23 | $124.71 | $7.73 | $23.19 | $38.65 | $0.00 |
| 2048 | $28.17 | $128.92 | $7.88 | $23.65 | $39.42 | $0.00 |
| 2049 | $29.12 | $133.24 | $8.04 | $24.13 | $40.21 | $0.00 |
| 2050 | $30.12 | $137.69 | $8.20 | $24.61 | $41.02 | $0.00 |
| 2051 | $31.14 | $142.26 | $8.37 | $25.10 | $41.84 | $0.00 |
| 2052 | $32.18 | $146.97 | $8.53 | $25.60 | $42.67 | $0.00 |
| 2053 | $33.26 | $151.80 | $8.71 | $26.12 | $43.53 | $0.00 |
| 2054 | $34.36 | $156.76 | $8.88 | $26.64 | $44.40 | $0.00 |
| 2055 | $35.50 | $161.87 | $9.06 | $27.17 | $45.28 | $0.00 |
| 2056 | $36.66 | $167.11 | $9.24 | $27.71 | $46.19 | $0.00 |
| 2057 | $37.86 | $172.51 | $9.42 | $28.27 | $47.11 | $0.00 |

## E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the three locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018. The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 GDPIPD of 113.416. The high, low and midpoint externality costs will be used in the $CO_2$ sensitivities as described above.

**Table IV-3: Externality Costs**

| MPUC Low Externality Costs 2018 $ per short ton | | | | |
|---|---|---|---|---|
| | Urban | Metro Fringe | Rural | <200mi |
| SO2 | $6,116 | $4,829 | $3,643 | $0 |
| NOx | $2,934 | $2,622 | $2,110 | $28 |
| PM2.5 | $10,697 | $6,856 | $3,654 | $872 |
| CO | $1.65 | $1.17 | $0.31 | $0.31 |
| Pb | $4,857 | $2,562 | $624 | $624 |

| MPUC High Externality Costs 2018 $ per short ton | | | | |
|---|---|---|---|---|
| | Urban | Metro Fringe | Rural | <200mi |
| SO2 | $15,288 | $12,030 | $8,878 | $0 |
| NOx | $8,390 | $7,798 | $6,771 | $158 |
| PM2.5 | $26,721 | $17,091 | $8,973 | $1,327 |
| CO | $3.51 | $2.08 | $0.63 | $0.63 |
| Pb | $6,011 | $3,094 | $695 | $695 |

| MPUC Midpoint Externality Costs 2018 $ per short ton | | | | |
|---|---|---|---|---|
| | Urban | Metro Fringe | Rural | <200mi |
| SO2 | $10,702 | $8,430 | $6,261 | $0 |
| NOx | $5,662 | $5,210 | $4,441 | $93 |
| PM2.5 | $18,709 | $11,974 | $6,313 | $1,099 |
| CO | $2.58 | $1.63 | $0.47 | $0.47 |
| Pb | $5,434 | $2,828 | $659 | $659 |

## F. Demand and Energy Forecast

The Company's fall 2019 load forecast is used as the base assumption and assumes that EV impacts growth continues throughout the forecast period. The energy efficiency (EE) forecast included in the base forecast developed by the Company's Load Forecasting department assumes somewhat less energy efficiency (EE) savings levels than those included in our initial Resource Plan's Preferred Plan. Please see Attachment A Section II for more information.

The "Load Forecast with EE" shown in Table IV-4 below is the starting point for the load inputs. In all modeling scenarios, the "EE" is removed – the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2048. In the initial filing, the three EE Bundles (discussed below) were optimized as Proview Alternatives. For this supplemental filing, the first two EE Bundles are included in all scenarios. The resulting forecast, before the optimized EE bundles are added, is shown below in Table IV-4 as "Forecast Without EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

### Table IV-4: Demand and Energy Forecast

| Demand and Energy Forecast | | | | |
|---|---|---|---|---|
| | Demand (MW) | | Energy (GWh) | |
| Year | Forecast with EE | Forecast without EE | Forecast with EE | Forecast without EE |
| 2018 | 9,152 | 9,152 | 43,914 | 43,914 |
| 2019 | 9,084 | 9,084 | 43,558 | 43,558 |
| 2020 | 9,099 | 9,230 | 43,170 | 43,806 |
| 2021 | 9,079 | 9,312 | 42,741 | 44,018 |
| 2022 | 9,126 | 9,462 | 42,628 | 44,549 |
| 2023 | 9,165 | 9,604 | 42,440 | 45,004 |
| 2024 | 9,184 | 9,728 | 42,339 | 45,555 |
| 2025 | 9,238 | 9,849 | 42,324 | 45,976 |
| 2026 | 9,311 | 9,992 | 42,470 | 46,565 |
| 2027 | 9,414 | 10,164 | 42,757 | 47,296 |
| 2028 | 9,504 | 10,327 | 43,221 | 48,216 |
| 2029 | 9,525 | 10,416 | 43,006 | 48,432 |
| 2030 | 9,605 | 10,566 | 43,224 | 49,093 |
| 2031 | 9,679 | 10,710 | 43,420 | 49,734 |
| 2032 | 9,775 | 10,880 | 43,903 | 50,678 |
| 2033 | 9,979 | 11,058 | 44,532 | 51,299 |
| 2034 | 10,190 | 11,246 | 45,426 | 52,203 |
| 2035 | 10,343 | 11,269 | 46,158 | 52,299 |
| 2036 | 10,502 | 11,325 | 47,028 | 52,527 |
| 2037 | 10,673 | 11,393 | 47,647 | 52,503 |
| 2038 | 10,803 | 11,420 | 48,209 | 52,422 |
| 2039 | 10,936 | 11,449 | 48,833 | 52,394 |
| 2040 | 11,073 | 11,518 | 49,603 | 52,729 |
| 2041 | 11,209 | 11,585 | 50,055 | 52,737 |
| 2042 | 11,338 | 11,645 | 50,635 | 52,873 |
| 2043 | 11,467 | 11,701 | 51,267 | 53,048 |
| 2044 | 11,614 | 11,780 | 52,023 | 53,374 |
| 2045 | 11,722 | 11,818 | 52,468 | 53,375 |
| 2046 | 11,839 | 11,865 | 53,010 | 53,473 |
| 2047 | 11,951 | 11,903 | 53,545 | 53,547 |
| 2048 | 12,021 | 11,998 | 54,150 | 54,160 |
| 2049 | 12,045 | 12,045 | 54,202 | 54,202 |
| 2050 | 12,097 | 12,097 | 54,407 | 54,407 |
| 2051 | 12,149 | 12,149 | 54,611 | 54,611 |
| 2052 | 12,199 | 12,199 | 54,947 | 54,947 |
| 2053 | 12,252 | 12,252 | 55,022 | 55,022 |
| 2054 | 12,305 | 12,305 | 55,226 | 55,226 |
| 2055 | 12,357 | 12,357 | 55,431 | 55,431 |
| 2056 | 12,409 | 12,409 | 55,765 | 55,765 |
| 2057 | 12,461 | 12,461 | 55,840 | 55,840 |

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high electrification load. These assumptions are shown in Table IV-5 and Table IV-6 and are incremental/decremental to the forecast shown in Table IV-4.

## Table IV-5: High Load Sensitivity

| High Electrification | | |
|---|---|---|
| Year | Energy (GWh) | Demand (MW) |
| 2018 | 35 | 8 |
| 2019 | 46 | 6 |
| 2020 | 59 | 7 |
| 2021 | 166 | 20 |
| 2022 | 276 | 33 |
| 2023 | 390 | 47 |
| 2024 | 507 | 62 |
| 2025 | 592 | 65 |
| 2026 | 692 | 77 |
| 2027 | 812 | 85 |
| 2028 | 939 | 98 |
| 2029 | 1,202 | 118 |
| 2030 | 1,578 | 162 |
| 2031 | 2,028 | 205 |
| 2032 | 2,538 | 251 |
| 2033 | 3,137 | 305 |
| 2034 | 3,857 | 367 |
| 2035 | 4,716 | 438 |
| 2036 | 5,657 | 515 |
| 2037 | 6,672 | 596 |
| 2038 | 7,741 | 679 |
| 2039 | 8,851 | 766 |
| 2040 | 9,996 | 854 |
| 2041 | 11,114 | 940 |
| 2042 | 12,199 | 1,025 |
| 2043 | 13,241 | 1,118 |
| 2044 | 14,229 | 1,796 |
| 2045 | 15,159 | 2,520 |
| 2046 | 16,037 | 3,173 |
| 2047 | 16,877 | 3,796 |
| 2048 | 17,696 | 4,647 |
| 2049 | 18,660 | 4,908 |
| 2050 | 19,530 | 5,407 |
| 2051 | 20,634 | 5,947 |
| 2052 | 21,645 | 6,418 |
| 2053 | 22,656 | 6,896 |
| 2054 | 23,666 | 7,384 |
| 2055 | 24,677 | 7,877 |
| 2056 | 25,688 | 8,352 |
| 2057 | 26,699 | 8,840 |

**Demand values are coincident to system peak*

# Table IV- 6: Low Load Sensitivity

| High DER Growth | | |
|---|---|---|
| Year | Energy (GWh) | Demand (Nameplate MW) |
| 2018 | 0 | 0 |
| 2019 | 0 | 0 |
| 2020 | 0 | 0 |
| 2021 | 207 | 122 |
| 2022 | 180 | 106 |
| 2023 | 159 | 94 |
| 2024 | 270 | 159 |
| 2025 | 258 | 152 |
| 2026 | 423 | 250 |
| 2027 | 423 | 250 |
| 2028 | 635 | 374 |
| 2029 | 641 | 379 |
| 2030 | 740 | 437 |
| 2031 | 826 | 487 |
| 2032 | 913 | 538 |
| 2033 | 996 | 588 |
| 2034 | 1,082 | 639 |
| 2035 | 1,167 | 689 |
| 2036 | 1,256 | 739 |
| 2037 | 1,338 | 790 |
| 2038 | 1,423 | 840 |
| 2039 | 1,509 | 891 |
| 2040 | 1,598 | 941 |
| 2041 | 1,631 | 963 |
| 2042 | 1,580 | 933 |
| 2043 | 1,529 | 903 |
| 2044 | 1,482 | 872 |
| 2045 | 1,425 | 842 |
| 2046 | 1,350 | 797 |
| 2047 | 1,296 | 765 |
| 2048 | 1,245 | 733 |
| 2049 | 1,187 | 701 |
| 2050 | 1,131 | 668 |
| 2051 | 1,063 | 628 |
| 2052 | 1,009 | 594 |
| 2053 | 932 | 550 |
| 2054 | 872 | 515 |
| 2055 | 807 | 476 |
| 2056 | 742 | 437 |
| 2057 | 671 | 396 |

## G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota DOC's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are decremental (reducing energy and demand) to the "Forecast without EE" shown in Table IV-4.

## Table IV- 7: Energy Efficiency Bundles

| | Energy(MWh) | | | Demand (MW) | | | Costs ($000) | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Bundle 1: Program | Bundle 2: Optimal | Bundle 3: Max | Bundle 1: Program | Bundle 2: Optimal | Bundle 3: Max | Bundle 1: Program | Bundle 2: Optimal | Bundle 3: Max |
| 2018 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2019 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2020 | 621 | 43 | 231 | 97 | 18 | 36 | 100,989 | 12,598 | 148,331 |
| 2021 | 1,326 | 91 | 493 | 207 | 38 | 77 | 113,525 | 13,905 | 167,221 |
| 2022 | 1,913 | 148 | 702 | 301 | 60 | 113 | 121,239 | 21,425 | 177,197 |
| 2023 | 2,555 | 211 | 928 | 407 | 86 | 154 | 133,614 | 23,931 | 196,474 |
| 2024 | 3,094 | 279 | 1,110 | 520 | 116 | 197 | 148,406 | 26,120 | 217,388 |
| 2025 | 3,629 | 346 | 1,289 | 635 | 146 | 241 | 152,433 | 26,077 | 223,293 |
| 2026 | 4,330 | 414 | 1,533 | 759 | 176 | 289 | 160,445 | 26,236 | 233,779 |
| 2027 | 5,054 | 482 | 1,785 | 886 | 206 | 338 | 167,718 | 26,637 | 242,963 |
| 2028 | 5,785 | 551 | 2,040 | 1,012 | 235 | 387 | 174,161 | 27,018 | 249,373 |
| 2029 | 6,454 | 606 | 2,280 | 1,127 | 259 | 432 | 162,170 | 23,442 | 233,114 |
| 2030 | 7,110 | 659 | 2,516 | 1,241 | 283 | 477 | 162,170 | 23,442 | 233,114 |
| 2031 | 7,753 | 710 | 2,748 | 1,354 | 307 | 522 | 162,170 | 23,442 | 233,114 |
| 2032 | 8,339 | 760 | 2,960 | 1,460 | 329 | 564 | 162,170 | 23,442 | 233,114 |
| 2033 | 8,909 | 808 | 3,168 | 1,564 | 352 | 605 | 162,170 | 23,442 | 233,114 |
| 2034 | 9,464 | 857 | 3,370 | 1,667 | 374 | 646 | 162,170 | 23,442 | 233,114 |
| 2035 | 9,250 | 846 | 3,294 | 1,648 | 370 | 638 | 0 | 0 | 0 |
| 2036 | 8,739 | 835 | 3,073 | 1,579 | 366 | 600 | 0 | 0 | 0 |
| 2037 | 8,088 | 789 | 2,829 | 1,470 | 347 | 557 | 0 | 0 | 0 |
| 2038 | 7,450 | 741 | 2,590 | 1,369 | 327 | 517 | 0 | 0 | 0 |
| 2039 | 6,841 | 685 | 2,372 | 1,267 | 304 | 475 | 0 | 0 | 0 |
| 2040 | 6,197 | 626 | 2,144 | 1,154 | 278 | 430 | 0 | 0 | 0 |
| 2041 | 5,543 | 562 | 1,919 | 1,036 | 250 | 384 | 0 | 0 | 0 |
| 2042 | 4,871 | 499 | 1,685 | 916 | 221 | 337 | 0 | 0 | 0 |
| 2043 | 4,220 | 434 | 1,457 | 796 | 191 | 291 | 0 | 0 | 0 |
| 2044 | 3,561 | 377 | 1,218 | 678 | 165 | 245 | 0 | 0 | 0 |
| 2045 | 2,912 | 318 | 990 | 562 | 139 | 201 | 0 | 0 | 0 |
| 2046 | 2,276 | 265 | 761 | 451 | 116 | 156 | 0 | 0 | 0 |
| 2047 | 1,746 | 212 | 573 | 349 | 93 | 117 | 0 | 0 | 0 |
| 2048 | 1,216 | 159 | 384 | 248 | 70 | 79 | 0 | 0 | 0 |
| 2049 | 686 | 106 | 195 | 146 | 46 | 40 | 0 | 0 | 0 |
| 2050 | 156 | 53 | 7 | 45 | 23 | 1 | 0 | 0 | 0 |
| 2051 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2052 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2053 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2054 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2055 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2056 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2057 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

***Demand values are coincident to system peak*

## H. Demand Response Forecast

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response "Bundles" are from the Brattle Potential Study provided as Appendix G2. The Bundles are incremental to the base demand response forecast. In the initial filing, the three DR Bundles were optimized as Proview Alternatives. For this Supplement, the first DR Bundle is included in all scenarios.

### Table IV-8: Demand Response Forecast

| Demand (MW) Adjusted For Reserve Margin | | | | | Costs ($000) | | |
|---|---|---|---|---|---|---|---|
| Year | Base Demand Response Forecast | Bundle 1 | Bundle 2 | Bundle 3 | Bundle 1 | Bundle 2 | Bundle 3 |
| 2018 | 852 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2019 | 928 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2020 | 1012 | 33 | 107 | 90 | 1,752 | 7,659 | 11,311 |
| 2021 | 1027 | 165 | 112 | 98 | 8,917 | 8,150 | 12,587 |
| 2022 | 1041 | 232 | 117 | 107 | 12,748 | 8,676 | 14,016 |
| 2023 | 1055 | 294 | 121 | 110 | 16,489 | 9,137 | 14,758 |
| 2024 | 1066 | 341 | 133 | 101 | 19,512 | 10,277 | 13,829 |
| 2025 | 1072 | 382 | 145 | 92 | 22,305 | 11,459 | 12,858 |
| 2026 | 1077 | 394 | 152 | 93 | 23,475 | 12,207 | 13,326 |
| 2027 | 1078 | 407 | 159 | 95 | 24,786 | 13,080 | 13,845 |
| 2028 | 1077 | 423 | 168 | 97 | 26,245 | 14,086 | 14,418 |
| 2029 | 1071 | 440 | 178 | 99 | 27,859 | 15,231 | 15,047 |
| 2030 | 1059 | 458 | 190 | 102 | 29,637 | 16,522 | 15,734 |
| 2031 | 1048 | 478 | 202 | 104 | 31,551 | 17,926 | 16,467 |
| 2032 | 1037 | 499 | 215 | 107 | 33,612 | 19,451 | 17,251 |
| 2033 | 1026 | 521 | 228 | 110 | 35,832 | 21,109 | 18,088 |
| 2034 | 1016 | 545 | 243 | 113 | 38,224 | 22,911 | 18,984 |
| 2035 | 1005 | 570 | 259 | 116 | 40,802 | 24,870 | 19,943 |
| 2036 | 995 | 596 | 275 | 120 | 43,582 | 26,999 | 20,971 |
| 2037 | 985 | 624 | 293 | 123 | 46,580 | 29,313 | 22,072 |
| 2038 | 976 | 654 | 312 | 127 | 49,814 | 31,829 | 23,253 |
| 2039 | 966 | 686 | 332 | 132 | 53,305 | 34,564 | 24,522 |
| 2040 | 957 | 720 | 353 | 136 | 57,073 | 37,537 | 25,884 |
| 2041 | 948 | 720 | 353 | 136 | 58,215 | 38,288 | 26,402 |
| 2042 | 939 | 720 | 353 | 136 | 59,379 | 39,054 | 26,930 |
| 2043 | 930 | 720 | 353 | 136 | 60,566 | 39,835 | 27,468 |
| 2044 | 922 | 720 | 353 | 136 | 61,778 | 40,632 | 28,018 |
| 2045 | 914 | 720 | 353 | 136 | 63,013 | 41,444 | 28,578 |
| 2046 | 906 | 720 | 353 | 136 | 64,274 | 42,273 | 29,150 |
| 2047 | 898 | 720 | 353 | 136 | 65,559 | 43,118 | 29,733 |
| 2048 | 890 | 720 | 353 | 136 | 66,870 | 43,981 | 30,327 |
| 2049 | 882 | 720 | 353 | 136 | 68,208 | 44,860 | 30,934 |
| 2050 | 875 | 720 | 353 | 136 | 69,572 | 45,758 | 31,552 |
| 2051 | 868 | 720 | 353 | 136 | 70,963 | 46,673 | 32,183 |
| 2052 | 860 | 720 | 353 | 136 | 72,382 | 47,606 | 32,827 |
| 2053 | 853 | 720 | 353 | 136 | 73,830 | 48,558 | 33,484 |
| 2054 | 847 | 720 | 353 | 136 | 75,307 | 49,530 | 34,153 |
| 2055 | 840 | 720 | 353 | 136 | 76,813 | 50,520 | 34,836 |
| 2056 | 833 | 720 | 353 | 136 | 78,349 | 51,531 | 35,533 |
| 2057 | 827 | 720 | 353 | 136 | 79,916 | 52,561 | 36,244 |

**Demand values are coincident to system peak.*

## I. Fuel Price Forecasts

Natural gas price forecasts are developed using a blend of market information (New York Mercantile Exchange, or NYMEX, futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five-year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, $SO_2$ costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table IV-9 below shows the market prices under zero $CO_2$ cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low-price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting when the long-term fundamentally-based forecasts are blended with market information (NYMEX futures prices).

## Table IV-9: Fuel and Market Price Forecasts

| | Base Price Forecast | | | | Low Price Forecast | | | | High Price Forecast | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fuel Price ($/mmBTu) | | Market Price ($/MWh) | | Fuel Price ($/mmBTu) | | Market Price ($/MWh) | | Fuel Price ($/mmBTu) | | Market Price ($/MWh) | |
| Year | Generic Coal | Ventura Hub | Minn Hub On-Peak | Minn Hub Off-Peak | Generic Coal | Ventura Hub | Minn Hub On-Peak | Minn Hub Off-Peak | Generic Coal | Ventura Hub | Minn Hub On-Peak | Minn Hub Off-Peak |
| 2018 | $2.19 | $2.74 | $28.60 | $21.61 | $2.19 | $2.74 | $28.60 | $21.61 | $2.19 | $2.74 | $28.60 | $21.61 |
| 2019 | $2.08 | $2.60 | $26.93 | $20.98 | $2.08 | $2.60 | $26.93 | $20.98 | $2.08 | $2.60 | $26.93 | $20.98 |
| 2020 | $2.11 | $2.26 | $25.78 | $20.13 | $2.11 | $2.26 | $25.78 | $20.13 | $2.11 | $2.26 | $25.78 | $20.13 |
| 2021 | $2.14 | $2.23 | $25.32 | $19.06 | $2.14 | $2.23 | $25.32 | $19.06 | $2.14 | $2.23 | $25.32 | $19.06 |
| 2022 | $2.19 | $2.33 | $26.92 | $20.45 | $2.17 | $2.28 | $26.33 | $20.00 | $2.24 | $2.38 | $27.52 | $20.90 |
| 2023 | $2.25 | $2.45 | $29.31 | $22.19 | $2.19 | $2.34 | $27.96 | $21.17 | $2.36 | $2.57 | $30.68 | $23.23 |
| 2024 | $2.30 | $2.58 | $30.00 | $23.20 | $2.22 | $2.40 | $27.94 | $21.60 | $2.46 | $2.76 | $32.16 | $24.87 |
| 2025 | $2.35 | $2.79 | $31.47 | $24.36 | $2.24 | $2.50 | $28.17 | $21.80 | $2.57 | $3.11 | $35.04 | $27.12 |
| 2026 | $2.40 | $2.98 | $32.30 | $24.99 | $2.27 | $2.58 | $28.01 | $21.67 | $2.69 | $3.42 | $37.09 | $28.70 |
| 2027 | $2.45 | $3.12 | $33.35 | $26.71 | $2.29 | $2.64 | $28.28 | $22.64 | $2.81 | $3.66 | $39.16 | $31.36 |
| 2028 | $2.51 | $3.26 | $34.09 | $26.97 | $2.32 | $2.71 | $28.25 | $22.35 | $2.93 | $3.92 | $40.92 | $32.38 |
| 2029 | $2.57 | $3.44 | $35.21 | $28.25 | $2.34 | $2.78 | $28.42 | $22.79 | $3.07 | $4.24 | $43.38 | $34.80 |
| 2030 | $2.62 | $3.70 | $38.27 | $30.69 | $2.37 | $2.88 | $29.83 | $23.92 | $3.20 | $4.71 | $48.76 | $39.09 |
| 2031 | $2.68 | $3.87 | $39.33 | $32.07 | $2.40 | $2.95 | $29.97 | $24.44 | $3.35 | $5.04 | $51.22 | $41.77 |
| 2032 | $2.75 | $4.02 | $39.75 | $33.14 | $2.43 | $3.01 | $29.71 | $24.77 | $3.51 | $5.34 | $52.76 | $43.99 |
| 2033 | $2.81 | $4.10 | $39.93 | $33.46 | $2.45 | $3.03 | $29.58 | $24.79 | $3.67 | $5.48 | $53.47 | $44.80 |
| 2034 | $2.87 | $4.20 | $41.13 | $34.56 | $2.48 | $3.07 | $30.08 | $25.28 | $3.83 | $5.70 | $55.76 | $46.86 |
| 2035 | $2.94 | $4.35 | $42.15 | $35.66 | $2.51 | $3.13 | $30.32 | $25.65 | $4.00 | $6.00 | $58.12 | $49.17 |
| 2036 | $2.99 | $4.47 | $42.79 | $36.60 | $2.53 | $3.17 | $30.37 | $25.97 | $4.14 | $6.24 | $59.80 | $51.13 |
| 2037 | $3.07 | $4.65 | $44.00 | $38.21 | $2.56 | $3.24 | $30.61 | $26.58 | $4.36 | $6.63 | $62.69 | $54.44 |
| 2038 | $3.14 | $4.86 | $44.95 | $39.45 | $2.60 | $3.31 | $30.60 | $26.85 | $4.58 | $7.08 | $65.43 | $57.42 |
| 2039 | $3.23 | $5.04 | $45.82 | $40.48 | $2.63 | $3.37 | $30.63 | $27.06 | $4.83 | $7.47 | $67.88 | $59.98 |
| 2040 | $3.31 | $5.22 | $46.61 | $41.48 | $2.66 | $3.43 | $30.61 | $27.25 | $5.06 | $7.87 | $70.25 | $62.53 |
| 2041 | $3.37 | $5.32 | $46.52 | $41.48 | $2.69 | $3.46 | $30.27 | $26.99 | $5.26 | $8.10 | $70.79 | $63.12 |
| 2042 | $3.45 | $5.47 | $47.61 | $42.64 | $2.72 | $3.51 | $30.57 | $27.38 | $5.51 | $8.43 | $73.40 | $65.74 |
| 2043 | $3.53 | $5.62 | $48.37 | $43.71 | $2.75 | $3.56 | $30.64 | $27.69 | $5.77 | $8.78 | $75.56 | $68.28 |
| 2044 | $3.62 | $5.78 | $49.72 | $44.99 | $2.79 | $3.61 | $31.04 | $28.09 | $6.05 | $9.17 | $78.79 | $71.29 |
| 2045 | $3.70 | $5.99 | $51.23 | $46.37 | $2.82 | $3.68 | $31.45 | $28.46 | $6.31 | $9.65 | $82.57 | $74.73 |
| 2046 | $3.78 | $6.17 | $52.49 | $47.53 | $2.85 | $3.73 | $31.74 | $28.74 | $6.59 | $10.09 | $85.85 | $77.73 |
| 2047 | $3.86 | $6.29 | $53.27 | $48.57 | $2.88 | $3.77 | $31.89 | $29.08 | $6.88 | $10.40 | $87.98 | $80.22 |
| 2048 | $3.95 | $6.46 | $54.39 | $49.88 | $2.91 | $3.82 | $32.15 | $29.49 | $7.20 | $10.80 | $90.96 | $83.42 |
| 2049 | $4.04 | $6.66 | $55.69 | $50.92 | $2.95 | $3.88 | $32.43 | $29.65 | $7.53 | $11.30 | $94.52 | $86.43 |
| 2050 | $4.13 | $6.77 | $56.64 | $51.71 | $2.98 | $3.91 | $32.70 | $29.85 | $7.87 | $11.60 | $96.97 | $88.53 |
| 2051 | $4.22 | $6.96 | $58.23 | $53.16 | $3.01 | $3.96 | $33.16 | $30.27 | $8.21 | $12.08 | $101.05 | $92.24 |
| 2052 | $4.31 | $7.13 | $59.62 | $54.42 | $3.04 | $4.01 | $33.56 | $30.63 | $8.57 | $12.51 | $104.64 | $95.53 |
| 2053 | $4.41 | $7.29 | $61.00 | $55.68 | $3.08 | $4.06 | $33.94 | $30.99 | $8.94 | $12.95 | $108.29 | $98.85 |
| 2054 | $4.50 | $7.46 | $62.38 | $56.95 | $3.11 | $4.10 | $34.33 | $31.34 | $9.33 | $13.39 | $111.97 | $102.21 |
| 2055 | $4.60 | $7.62 | $63.76 | $58.21 | $3.14 | $4.15 | $34.71 | $31.69 | $9.73 | $13.83 | $115.69 | $105.61 |
| 2056 | $4.69 | $7.79 | $65.15 | $59.47 | $3.17 | $4.19 | $35.09 | $32.03 | $10.12 | $14.28 | $119.45 | $109.05 |
| 2057 | $4.79 | $7.95 | $66.53 | $60.73 | $3.21 | $4.24 | $35.46 | $32.37 | $10.52 | $14.74 | $123.26 | $112.52 |

**Coal prices are delivered prices, while gas and market prices are hub prices.*

## J. Baseload Retirement "Leave Behind" Costs

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three-year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2020).

- King: $48 million
- Sherco 3: $48 million
- Monticello: $96 million
- Prairie Island 1: $96 million
- Prairie Island 2: $96 million

## K. Surplus Capacity Credit

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

**Table IV-10: Surplus Capacity Credit**

| Surplus Capacity Credit | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
| $/kw-mo | 4.57 | 4.66 | 4.75 | 4.85 | 4.95 | 5.05 | 5.15 | 5.25 | 5.35 | 5.46 | 5.57 | 5.68 | 5.80 | 5.91 | 6.03 | 6.15 | 6.27 | 6.40 | 6.53 | 6.66 |
| | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 |
| $/kw-mo | 6.79 | 6.93 | 7.07 | 7.21 | 7.35 | 7.50 | 7.65 | 7.80 | 7.96 | 8.12 | 8.28 | 8.44 | 8.61 | 8.79 | 8.96 | 9.14 | 9.32 | 9.51 | 9.70 | 9.89 |

## L. Effective Load Carrying Capability Capacity Credit for Wind, Solar, and Battery Resources

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 16.7 percent of their nameplate rating per MISO 2020/2021 Wind Capacity Report. The ELCC for generic solar is based on the values provided in MISO's MTEP 2019 in Appendix E,[3] and is 50 percent of the alternating current (AC) nameplate capacity through 2023, declining 2 percent annually to 30 percent by 2033 where it remains for the rest of the forecast period. The ELCC assigned for a generic 4-hour battery is equal to 100 percent of the AC equivalent capacity. The ELCC used for hybrid options are the same as the individual components.

## M. Spinning Reserve Requirement

Spinning reserve is the online reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 137 MW and is based on a 12-month rolling average of spinning reserves carried by the NSP System within MISO.

## N. Emergency Energy

Emergency energy is used to cover events where there are not enough resources or market purchase energy available to meet system energy requirements. In Strategist, this is set to $500/MWh. Encompass uses the default value of $10,000/MWh. The primary reason for this difference is the way the models utilize this input. In Strategist's dispatch approach, the emergency energy is determined after the dispatch, when all resources have been utilized and an energy shortfall still exists. In EnCompass, emergency energy is a "soft constraint" that allows emergency energy to "dispatch" as a last resort resource, in order for the model to find a feasible solution. The EnCompass price is set to a high level to ensure that all other available resources – including those that may have a very high effective $/MWh cost resulting from startup costs spread over a very small required run time – are utilized before emergency energy.

## O. Transmission Delivery Costs and Interconnection Costs

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system.

[3] Available at: https://cdn.misoenergy.org//MTEP19%20Appendix%20E-Futures%20Assumptions382958.pdf

We note additionally that interconnection costs for generic resources are included in the capital costs in Table IV-14 in Part U of this section and represent "behind the fence" costs associated with substation and representative gen-tie construction.

**Table IV-11: Transmission Delivery Costs**

| Transmission Delivery Costs | | | | |
|---|---|---|---|---|
| | CC | CT | Wind | Solar |
| $/kw | 500 | 200 | 500 | 200 |

## P. Integration and Congestion Costs

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were not included in the model.

**Table IV-12: Integration Costs**

| Integration Costs ($/MWh) | | |
|---|---|---|
| Year | Wind | Solar |
| 2018 | 0.00 | 0.00 |
| 2019 | 0.00 | 0.00 |
| 2020 | 0.41 | 0.41 |
| 2021 | 0.42 | 0.42 |
| 2022 | 0.43 | 0.43 |
| 2023 | 0.44 | 0.44 |
| 2024 | 0.45 | 0.45 |
| 2025 | 0.46 | 0.46 |
| 2026 | 0.47 | 0.47 |
| 2027 | 0.48 | 0.48 |
| 2028 | 0.49 | 0.49 |
| 2029 | 0.49 | 0.49 |
| 2030 | 0.50 | 0.50 |
| 2031 | 0.51 | 0.51 |
| 2032 | 0.53 | 0.53 |
| 2033 | 0.54 | 0.54 |
| 2034 | 0.55 | 0.55 |
| 2035 | 0.56 | 0.56 |
| 2036 | 0.57 | 0.57 |
| 2037 | 0.58 | 0.58 |
| 2038 | 0.59 | 0.59 |
| 2039 | 0.60 | 0.60 |
| 2040 | 0.62 | 0.62 |
| 2041 | 0.63 | 0.63 |
| 2042 | 0.64 | 0.64 |
| 2043 | 0.65 | 0.65 |
| 2044 | 0.67 | 0.67 |
| 2045 | 0.68 | 0.68 |
| 2046 | 0.69 | 0.69 |
| 2047 | 0.71 | 0.71 |
| 2048 | 0.72 | 0.72 |
| 2049 | 0.74 | 0.74 |
| 2050 | 0.75 | 0.75 |
| 2051 | 0.77 | 0.77 |
| 2052 | 0.78 | 0.78 |
| 2053 | 0.80 | 0.80 |
| 2054 | 0.81 | 0.81 |
| 2055 | 0.83 | 0.83 |
| 2056 | 0.84 | 0.84 |
| 2057 | 0.86 | 0.86 |

## Q. Distributed Solar Generation and Community Solar Gardens

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts. Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a twenty-five-year service life. After a "vintage" of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs.

### Table IV-13: Distributed Solar Forecast

| Distributed Solar (Nameplate MW) | | | |
|---|---|---|---|
| Year | Solar Rewards | Community Gardens | Total |
| 2018 | 29 | 246 | 274 |
| 2019 | 61 | 504 | 565 |
| 2020 | 80 | 658 | 738 |
| 2021 | 95 | 714 | 809 |
| 2022 | 109 | 787 | 897 |
| 2023 | 123 | 841 | 964 |
| 2024 | 138 | 852 | 989 |
| 2025 | 152 | 853 | 1,005 |
| 2026 | 166 | 854 | 1,020 |
| 2027 | 180 | 855 | 1,035 |
| 2028 | 194 | 857 | 1,050 |
| 2029 | 208 | 858 | 1,066 |
| 2030 | 222 | 859 | 1,080 |
| 2031 | 236 | 860 | 1,095 |
| 2032 | 249 | 861 | 1,110 |
| 2033 | 263 | 862 | 1,125 |
| 2034 | 276 | 863 | 1,140 |
| 2035 | 290 | 864 | 1,154 |
| 2036 | 303 | 866 | 1,169 |
| 2037 | 317 | 867 | 1,184 |
| 2038 | 330 | 868 | 1,198 |
| 2039 | 343 | 869 | 1,212 |
| 2040 | 357 | 870 | 1,227 |
| 2041 | 370 | 871 | 1,241 |
| 2042 | 383 | 869 | 1,252 |
| 2043 | 396 | 852 | 1,247 |
| 2044 | 409 | 830 | 1,239 |
| 2045 | 421 | 818 | 1,239 |
| 2046 | 434 | 814 | 1,248 |
| 2047 | 447 | 808 | 1,255 |
| 2048 | 460 | 805 | 1,264 |
| 2049 | 472 | 805 | 1,277 |
| 2050 | 491 | 806 | 1,297 |
| 2051 | 504 | 807 | 1,311 |
| 2052 | 518 | 808 | 1,326 |
| 2053 | 531 | 809 | 1,340 |
| 2054 | 545 | 810 | 1,355 |
| 2055 | 559 | 811 | 1,369 |
| 2056 | 572 | 812 | 1,384 |
| 2057 | 586 | 812 | 1,398 |

## R. Owned Unit Modeled Operating Characteristics and Costs

Company-owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for $SO_2$, $NO_x$, $CO_2$, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

## S. Thermal PPA Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for $SO_2$, $NO_x$, $CO_2$, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

## T. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each renewable energy unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind and solar hourly patterns are developed through a "Typical Meteorological Year" process where individual months are selected from the years 2017-2020 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each unit. For units where generation data is not complete or not available, data from a nearby similar unit is used.

## U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic renewable and battery costs are based on data from the NREL 2019 ATB. Utility-scale wind and solar costs shown in Tables IV-18 through IV-20 include transmission costs from Table IV-11 while DG/distributed solar does not.

The modeling no longer assumes "no going back" on renewables, which was the replacement of renewable resources for a similar resource when they reached the end of their life, but rather allows all renewable additions to be optimized.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind, solar, and battery costs are also based on the 2019 ATB data. Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for $SO_2$, $NO_x$, $CO_2$, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

## Table IV-14: Thermal Generic Information (Costs in 2018 Dollars)

| Thermal Generic Information | | | | | |
|---|---|---|---|---|---|
| **Resource** | **Sherco CC** | **Generic CC** | **Generic CT** | **Generic CT** | **Generic CT** |
| Technology | 7H | 7H | 7H | 7F | 7H |
| Location Type | Brownfield | Greenfield | Brownfield | Brownfield | Greenfield |
| Cooling Type | Wet | Dry | Dry | Dry | Dry |
| Book life | 40 | 40 | 40 | 40 | 40 |
| Nameplate Capacity (MW) | 835 | 901 | 374 | 232 | 374 |
| Summer Peak Capacity (MW) | 750 | 856 | 331 | 206 | 331 |
| | | | | | |
| Capital Cost ($000) 2018$ | $837,068 | $906,588 | $174,700 | $114,766 | $193,500 |
| Electric Transmission Delivery ($000) 2018$ | NA | $410,505 | NA | NA | $74,804 |
| Ongoing Capital Expenditures ($000-yr) 2018$ | $6,200 | $6,200 | $1,784 | $892 | $1,784 |
| Gas Demand ($000-yr) 2018$ | $31,725 | $19,058 | $2,165 | $1,342 | $2,165 |
| | | | | | |
| Capital Cost ($/kW) 2018$ | $1,002 | $1,006 | $467 | $495 | $517 |
| Electric Transmission Delivery ($/kW) 2018$ | NA | $455 | NA | NA | $200 |
| Ongoing Capital Expenditures ($/kW-yr) 2018$ | $7.42 | $6.88 | $4.77 | $3.85 | $4.77 |
| Gas Demand ($/kW-yr) 2018$ | $37.98 | $21.14 | $5.79 | $5.79 | $5.79 |
| | | | | | |
| Fixed O&M Cost ($000/yr) 2018$ | $6,592 | $6,592 | $1,253 | $1,203 | $1,253 |
| Variable O&M Cost ($/MWh) 2018$ | $1.04 | $1.04 | $0.99 | $1.03 | $0.99 |
| Levelized $/kw-mo (All Fixed Costs) $2018 | $15.26 | $16.06 | $5.91 | $6.22 | $8.06 |
| | | | | | |
| Summer Heat Rate 100% Loading (btu/kWh) | 6,359 | 6,848 | 9,264 | 10,025 | 9,264 |
| Summer Heat Rate 75% Loading (btu/kWh) | 6,547 | 6,874 | 9,738 | 10,581 | 9,738 |
| Summer Heat Rate 50% Loading (btu/kWh) | 6,985 | 7,334 | 11,120 | 12,515 | 11,120 |
| Summer Heat Rate 25% Loading (btu/kWh) | 8,004 | 8,404 | 11,558 | 13,430 | 11,558 |
| Forced Outage Rate | 3% | 3% | 3% | 3% | 3% |
| Maintenance (weeks/yr) | 5 | 5 | 2 | 2 | 2 |
| | | | | | |
| CO2 Emissions (lbs/MMBtu) | 118 | 118 | 118 | 118 | 118 |
| SO2 Emissions (lbs/MWh) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| NOx Emissions (lbs/MWh) | 0.05 | 0.05 | 0.90 | 0.32 | 0.90 |
| PM10 Emissions (lbs/MWh) | 0.02 | 0.02 | 0.03 | 0.03 | 0.03 |
| Mercury Emissions (lbs/MMWh) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## Table IV-15: Renewable Generic Information (Costs in 2018 Dollars)

| Renewable Generic Information | | | | |
|---|---|---|---|---|
| **Resource** | **Wind** | **Utility Scale Solar** | **Distributed Solar Commercial** | **Distributed Solar Residential** |
| ELCC Capacity Credit (%) | 16.7% | 50% declines to 30% | | |
| Capacity Factor | 50.0% | 22.0% | 18.0% | 18.0% |
| Book life | 25 | 25 | 25 | 25 |
| Electric Transmission Delivery ($/kW) | 500 | 200 | 0 | 0 |

**Table IV-16: Storage Generic Information (Costs in 2018 Dollars)**

| Storage Generic Information | |
|---|---|
| **Resource** | **Battery** |
| Technology | Li Ion |
| Location Type | NA |
| Book life | 40 |
| Nameplate Capacity (MW) | 321 |
| Summer Peak Capacity (MW) | 321 |
| Storage Volume (hrs) | 4 |
| Cycle Efficiency (%) | 85 |
| Equivalent Full Cycles per Year | 250 |
| Electric Transmission Delivery ($000) 2018$ | 0 |
| Levelized $/kw-mo (All Fixed Costs) $2023 | $18.18 |

## Table IV-17: Levelized Capacity Costs by Year

| Levelized Capacity Costs by In-Service Year ($/kw-mo) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| COD | CT - 7H Greenfield | CT - 7F Brownfield | CT - 7H Brownfield | CC | Sherco CC | Base Battery | Low Battery | High Battery |
| 2018 | $8.06 | $6.22 | $5.91 | $16.06 | $15.26 | | | |
| 2019 | $8.22 | $6.34 | $6.02 | $16.38 | $15.56 | | | |
| 2020 | $8.38 | $6.47 | $6.15 | $16.71 | $15.87 | $20.04 | $17.86 | $22.94 |
| 2021 | $8.55 | $6.60 | $6.27 | $17.05 | $16.19 | $19.44 | $16.81 | $23.19 |
| 2022 | $8.72 | $6.73 | $6.39 | $17.39 | $16.51 | $18.82 | $15.73 | $23.45 |
| 2023 | $8.89 | $6.86 | $6.52 | $17.73 | $16.85 | $18.18 | $14.62 | $23.71 |
| 2024 | $9.07 | $7.00 | $6.65 | $18.09 | $17.18 | $17.52 | $13.47 | $23.97 |
| 2025 | $9.25 | $7.14 | $6.78 | $18.45 | $17.53 | $16.84 | $12.30 | $24.24 |
| 2026 | $9.44 | $7.28 | $6.92 | $18.82 | $17.88 | $16.63 | $11.75 | $24.51 |
| 2027 | $9.63 | $7.43 | $7.06 | $19.20 | $18.23 | $16.41 | $11.18 | $24.78 |
| 2028 | $9.82 | $7.58 | $7.20 | $19.58 | $18.60 | $16.19 | $10.60 | $25.06 |
| 2029 | $10.02 | $7.73 | $7.34 | $19.97 | $18.97 | $15.95 | $10.00 | $25.34 |
| 2030 | $10.22 | $7.88 | $7.49 | $20.37 | $19.35 | $15.71 | $9.38 | $25.62 |
| 2031 | $10.42 | $8.04 | $7.64 | $20.78 | $19.74 | $15.83 | $9.38 | $26.06 |
| 2032 | $10.63 | $8.20 | $7.79 | $21.19 | $20.13 | $15.94 | $9.37 | $26.50 |
| 2033 | $10.84 | $8.36 | $7.95 | $21.62 | $20.53 | $16.04 | $9.36 | $26.94 |
| 2034 | $11.06 | $8.53 | $8.11 | $22.05 | $20.94 | $16.15 | $9.35 | $27.40 |
| 2035 | $11.28 | $8.70 | $8.27 | $22.49 | $21.36 | $16.26 | $9.33 | $27.86 |
| 2036 | $11.50 | $8.88 | $8.44 | $22.94 | $21.79 | $16.36 | $9.31 | $28.32 |
| 2037 | $11.73 | $9.05 | $8.60 | $23.40 | $22.23 | $16.46 | $9.28 | $28.80 |
| 2038 | $11.97 | $9.24 | $8.78 | $23.87 | $22.67 | $16.56 | $9.25 | $29.28 |
| 2039 | $12.21 | $9.42 | $8.95 | $24.34 | $23.12 | $16.65 | $9.21 | $29.78 |
| 2040 | $12.45 | $9.61 | $9.13 | $24.83 | $23.59 | $16.74 | $9.17 | $30.27 |
| 2041 | $12.70 | $9.80 | $9.31 | $25.33 | $24.06 | $16.83 | $9.13 | $30.78 |
| 2042 | $12.96 | $10.00 | $9.50 | $25.83 | $24.54 | $16.76 | $9.00 | $30.97 |
| 2043 | $13.22 | $10.20 | $9.69 | $26.35 | $25.03 | $16.66 | $8.85 | $31.12 |
| 2044 | $13.48 | $10.40 | $9.88 | $26.88 | $25.53 | $16.55 | $8.70 | $31.25 |
| 2045 | $13.75 | $10.61 | $10.08 | $27.42 | $26.04 | $16.42 | $8.53 | $31.35 |
| 2046 | $14.02 | $10.82 | $10.28 | $27.96 | $26.56 | $16.26 | $8.35 | $31.41 |
| 2047 | $14.30 | $11.04 | $10.49 | $28.52 | $27.09 | $16.08 | $8.16 | $31.44 |
| 2048 | $14.59 | $11.26 | $10.70 | $29.09 | $27.64 | $15.88 | $7.95 | $31.42 |
| 2049 | $14.88 | $11.48 | $10.91 | $29.68 | $28.19 | $15.65 | $7.73 | $31.35 |
| 2050 | $15.18 | $11.71 | $11.13 | $30.27 | $28.75 | $15.39 | $7.49 | $31.23 |
| 2051 | $15.48 | $11.95 | $11.35 | $30.88 | $29.33 | $15.70 | $7.64 | $31.85 |
| 2052 | $15.79 | $12.19 | $11.58 | $31.49 | $29.91 | $16.01 | $7.79 | $32.49 |
| 2053 | $16.11 | $12.43 | $11.81 | $32.12 | $30.51 | $16.33 | $7.95 | $33.14 |
| 2054 | $16.43 | $12.68 | $12.05 | $32.76 | $31.12 | $16.66 | $8.10 | $33.80 |
| 2055 | $16.76 | $12.93 | $12.29 | $33.42 | $31.75 | $16.99 | $8.27 | $34.48 |
| 2056 | $17.10 | $13.19 | $12.54 | $34.09 | $32.38 | $17.33 | $8.43 | $35.17 |
| 2057 | $17.44 | $13.45 | $12.79 | $34.77 | $33.03 | $17.68 | $8.60 | $35.87 |

## Table IV-18: Base Renewable Levelized Costs by Year

| Levelized Costs by First Full Year of Operation $/MWh (LCOE) | | | | |
|---|---|---|---|---|
| | Wind | Utility Scale Solar | Distributed Solar Commercial | Distributed Solar Residential |
| 2018 | | | | |
| 2019 | | | | |
| 2020 | $28.29 | $46.12 | $61.16 | $92.16 |
| 2021 | $32.32 | $48.12 | $64.63 | $94.44 |
| 2022 | $36.53 | $53.73 | $74.07 | $105.71 |
| 2023 | $40.91 | $53.81 | $73.54 | $102.31 |
| 2024 | $36.03 | $53.87 | $72.96 | $98.77 |
| 2025 | $50.24 | $53.93 | $72.35 | $95.07 |
| 2026 | $50.28 | $53.97 | $71.70 | $91.23 |
| 2027 | $50.32 | $53.99 | $71.00 | $87.23 |
| 2028 | $50.36 | $54.01 | $70.26 | $83.07 |
| 2029 | $50.41 | $54.00 | $69.47 | $78.75 |
| 2030 | $50.46 | $53.98 | $68.64 | $74.26 |
| 2031 | $51.13 | $54.60 | $69.31 | $74.25 |
| 2032 | $51.81 | $55.21 | $69.97 | $74.23 |
| 2033 | $52.50 | $55.83 | $70.64 | $74.17 |
| 2034 | $53.19 | $56.45 | $71.31 | $74.08 |
| 2035 | $53.89 | $57.07 | $71.98 | $73.96 |
| 2036 | $54.60 | $57.70 | $72.65 | $73.81 |
| 2037 | $55.31 | $58.32 | $73.32 | $73.62 |
| 2038 | $56.03 | $58.96 | $73.98 | $73.40 |
| 2039 | $56.76 | $59.59 | $74.65 | $73.15 |
| 2040 | $57.49 | $60.23 | $75.31 | $72.86 |
| 2041 | $58.23 | $60.94 | $75.87 | $73.52 |
| 2042 | $58.98 | $61.66 | $76.42 | $74.18 |
| 2043 | $59.73 | $62.38 | $76.97 | $74.84 |
| 2044 | $60.49 | $63.10 | $77.51 | $75.49 |
| 2045 | $61.26 | $63.83 | $78.04 | $76.15 |
| 2046 | $62.03 | $64.57 | $78.56 | $77.43 |
| 2047 | $62.81 | $65.31 | $79.08 | $78.73 |
| 2048 | $63.60 | $66.05 | $79.58 | $80.05 |
| 2049 | $64.39 | $66.80 | $80.08 | $81.40 |
| 2050 | $65.19 | $67.55 | $80.56 | $82.76 |
| 2051 | $66.49 | $68.90 | $82.17 | $84.42 |
| 2052 | $67.82 | $70.28 | $83.81 | $86.11 |
| 2053 | $69.17 | $71.69 | $85.49 | $87.83 |
| 2054 | $70.56 | $73.12 | $87.20 | $89.59 |
| 2055 | $71.97 | $74.58 | $88.94 | $91.38 |
| 2056 | $73.41 | $76.08 | $90.72 | $93.20 |
| 2057 | $74.88 | $77.60 | $92.54 | $95.07 |

**Distributed Solar costs represent at the meter values before grossing up for losses.*

## Table IV-19: Low Renewable Levelized Costs by Year

| Low Levelized Costs by First Full Year of Operation $/MWh (LCOE) | | | | |
|---|---|---|---|---|
| | Wind | Utility Scale Solar | Distributed Solar Commercial | Distributed Solar Residential |
| 2018 | | | | |
| 2019 | | | | |
| 2020 | $25.70 | $40.39 | $46.57 | $80.57 |
| 2021 | $28.96 | $41.44 | $44.77 | $80.58 |
| 2022 | $32.43 | $45.30 | $50.58 | $87.80 |
| 2023 | $36.12 | $44.66 | $49.46 | $82.47 |
| 2024 | $30.57 | $43.99 | $48.30 | $76.99 |
| 2025 | $44.15 | $43.29 | $47.11 | $71.34 |
| 2026 | $43.59 | $42.57 | $45.87 | $65.52 |
| 2027 | $43.05 | $41.82 | $44.59 | $59.54 |
| 2028 | $42.55 | $41.04 | $43.26 | $53.38 |
| 2029 | $42.07 | $40.23 | $41.89 | $47.05 |
| 2030 | $41.62 | $39.40 | $40.48 | $40.54 |
| 2031 | $42.10 | $39.43 | $40.22 | $40.29 |
| 2032 | $42.57 | $39.45 | $39.94 | $40.02 |
| 2033 | $43.05 | $39.46 | $39.63 | $39.73 |
| 2034 | $43.53 | $39.45 | $39.30 | $39.41 |
| 2035 | $44.01 | $39.43 | $38.95 | $39.06 |
| 2036 | $44.50 | $39.59 | $38.57 | $38.69 |
| 2037 | $44.98 | $39.74 | $38.16 | $38.29 |
| 2038 | $45.47 | $39.88 | $37.72 | $37.86 |
| 2039 | $45.96 | $40.01 | $37.25 | $37.41 |
| 2040 | $46.45 | $40.14 | $36.75 | $36.92 |
| 2041 | $46.94 | $40.51 | $37.10 | $37.03 |
| 2042 | $47.43 | $40.89 | $37.46 | $37.13 |
| 2043 | $47.92 | $41.26 | $37.81 | $37.22 |
| 2044 | $48.41 | $41.63 | $38.17 | $37.31 |
| 2045 | $48.90 | $42.01 | $37.15 | $37.38 |
| 2046 | $49.40 | $42.47 | $37.76 | $37.91 |
| 2047 | $49.89 | $42.93 | $38.38 | $38.45 |
| 2048 | $50.38 | $43.40 | $39.01 | $39.00 |
| 2049 | $50.88 | $43.87 | $39.65 | $39.55 |
| 2050 | $51.37 | $44.34 | $40.30 | $40.11 |
| 2051 | $52.40 | $45.23 | $41.10 | $40.92 |
| 2052 | $53.44 | $46.13 | $41.93 | $41.74 |
| 2053 | $54.51 | $47.06 | $42.76 | $42.57 |
| 2054 | $55.60 | $48.00 | $43.62 | $43.42 |
| 2055 | $56.71 | $48.96 | $44.49 | $44.29 |
| 2056 | $57.85 | $49.94 | $45.38 | $45.18 |
| 2057 | $59.01 | $50.94 | $46.29 | $46.08 |

**Distributed Solar costs represent at the meter values before grossing up for losses.*

## Table IV-20: High Renewable Levelized Costs by Year

| High Levelized Costs by First Full Year of Operation $/MWh (LCOE) | | | | |
|---|---|---|---|---|
| | Wind | Utility Scale Solar | Distributed Solar Commercial | Distributed Solar Residential |
| 2018 | | | | |
| 2019 | | | | |
| 2020 | $31.34 | $47.98 | $68.45 | $98.01 |
| 2021 | $36.42 | $50.93 | $73.59 | $105.38 |
| 2022 | $41.69 | $58.00 | $86.61 | $124.02 |
| 2023 | $47.16 | $59.16 | $88.34 | $126.50 |
| 2024 | $43.38 | $60.35 | $90.11 | $129.03 |
| 2025 | $58.71 | $61.55 | $91.91 | $131.61 |
| 2026 | $59.88 | $62.79 | $93.75 | $134.24 |
| 2027 | $61.08 | $64.04 | $95.63 | $136.93 |
| 2028 | $62.30 | $65.32 | $97.54 | $139.67 |
| 2029 | $63.55 | $66.63 | $99.49 | $142.46 |
| 2030 | $64.82 | $67.96 | $101.48 | $145.31 |
| 2031 | $66.11 | $69.32 | $103.51 | $148.22 |
| 2032 | $67.43 | $70.71 | $105.58 | $151.18 |
| 2033 | $68.78 | $72.12 | $107.69 | $154.20 |
| 2034 | $70.16 | $73.56 | $109.85 | $157.29 |
| 2035 | $71.56 | $75.03 | $112.04 | $160.43 |
| 2036 | $72.99 | $76.53 | $114.28 | $163.64 |
| 2037 | $74.45 | $78.07 | $116.57 | $166.91 |
| 2038 | $75.94 | $79.63 | $118.90 | $170.25 |
| 2039 | $77.46 | $81.22 | $121.28 | $173.66 |
| 2040 | $79.01 | $82.84 | $123.70 | $177.13 |
| 2041 | $80.59 | $84.50 | $126.18 | $180.67 |
| 2042 | $82.20 | $86.19 | $128.70 | $184.29 |
| 2043 | $83.85 | $87.91 | $131.28 | $187.97 |
| 2044 | $85.52 | $89.67 | $133.90 | $191.73 |
| 2045 | $87.23 | $91.47 | $136.58 | $195.57 |
| 2046 | $88.98 | $93.30 | $139.31 | $199.48 |
| 2047 | $90.76 | $95.16 | $142.10 | $203.47 |
| 2048 | $92.57 | $97.06 | $144.94 | $207.54 |
| 2049 | $94.43 | $99.01 | $147.84 | $211.69 |
| 2050 | $96.31 | $100.99 | $150.79 | $215.92 |
| 2051 | $98.24 | $103.01 | $153.81 | $220.24 |
| 2052 | $100.20 | $105.07 | $156.89 | $224.65 |
| 2053 | $102.21 | $107.17 | $160.02 | $229.14 |
| 2054 | $104.25 | $109.31 | $163.23 | $233.72 |
| 2055 | $106.34 | $111.50 | $166.49 | $238.40 |
| 2056 | $108.46 | $113.73 | $169.82 | $243.16 |
| 2057 | $110.63 | $116.00 | $173.22 | $248.03 |

**Distributed Solar costs represent at the meter values before grossing up for losses.*

## V. Market Purchases and Sales Carbon Rate

In order to estimate emissions rates associated with market purchases, the Company assumes an annual average carbon emissions pounds/MWh rate, as shown in the table below. These estimates were developed using MISO's MTEP Futures modeling results. Market sales emissions rates reflect an average emissions rate for our system resources and vary according to each individual scenario and sensitivity capacity expansion portfolio.

**Table IV-21: Market Purchase Carbon Rate**

| Market Purchase CO2 Rate | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** |
| lbs/MWh | 1372 | 1307 | 1241 | 1176 | 1110 | 1045 | 1042 | 1039 | 1036 | 1034 | 1031 | 1018 | 1006 | 993 | 980 | 968 | 955 | 943 | 930 | 917 |
| | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **2046** | **2047** | **2048** | **2049** | **2050** | **2051** | **2052** | **2053** | **2054** | **2055** | **2056** | **2057** |
| lbs/MWh | 905 | 892 | 880 | 867 | 854 | 842 | 829 | 817 | 804 | 792 | 779 | 766 | 754 | 741 | 729 | 716 | 703 | 691 | 678 | 666 |

## W. Sherco CC Size Alternatives

In its October 17, 2019 hearing in this docket, the Commission directed the Company to model different size alternatives for the planned Sherco CC. The Company developed three size alternatives – two smaller units and one larger unit – to test in sensitivity modeling. Cost and performance assumptions for each of these alternatives are detailed in Table IV-22 below.

## Table IV-22: Sherco CC Alternatives

| Thermal Generic Information | | | | |
|---|---|---|---|---|
| **Resource** | **Sherco CC** | **7HA.01 1x1** | **7HA.02 1x1** | **7HA.02 2x1** |
| Technology | 7H | 7H | 7H | 7F |
| Location Type | Brownfield | Brownfield | Brownfield | Brownfield |
| Cooling Type | Wet | Wet | Wet | Wet |
| Book life | 40 | 40 | 40 | 40 |
| Nameplate Capacity (MW) | 835 | 405 | 592 | 1202 |
| Summer Peak Capacity (MW) | 750 | 395 | 576 | 1170 |
| | | | | |
| Capital Cost ($000) 2018$ | $837,068 | $473,751 | $629,206 | $941,199 |
| Electric Transmission Delivery ($000) 2018$ | NA | NA | NA | NA |
| Ongoing Capital Expenditures ($000-yr) 2018$ | $6,200 | $4,190 | $4,190 | $8,775 |
| Gas Demand ($000-yr) 2018$ | $31,723 | $31,723 | $31,723 | $31,723 |
| | | | | |
| Capital Cost ($/kW) 2018$ | $1,002 | $1,171 | $1,064 | $783 |
| Electric Transmission Delivery ($/kW) 2018$ | NA | NA | NA | NA |
| Ongoing Capital Expenditures ($/kW-yr) 2018$ | $7.43 | $10.35 | $7.08 | $7.30 |
| Gas Demand ($/kW-yr) 2018$ | $37.99 | $78.41 | $53.63 | $26.38 |
| | | | | |
| Fixed O&M Cost ($000/yr) 2018$ | $6,592 | $7,150 | $7,150 | $8,647 |
| Variable O&M Cost ($/MWh) 2018$ | $1.04 | $1.72 | $1.72 | $1.09 |
| Levelized $/kw-mo (All Fixed Costs) $2018 | $15.26 | $18.36 | $14.11 | $10.95 |
| | | | | |
| Summer Heat Rate 100% Loading (btu/kWh) | 6,359 | 6,322 | 6,208 | 6,452 |
| Summer Heat Rate 75% Loading (btu/kWh) | 6,547 | 6,419 | 6,257 | 6,403 |
| Summer Heat Rate 50% Loading (btu/kWh) | 6,985 | 6,681 | 6,516 | 6,812 |
| Summer Heat Rate 25% Loading (btu/kWh) | 8,004 | 7,553 | 7,388 | 7,479 |
| Forced Outage Rate | 3% | 3% | 3% | 3% |
| Maintenance (weeks/yr) | 5 | 5 | 5 | 5 |
| | | | | |
| CO2 Emissions (lbs/MMBtu) | 118 | 118 | 118 | 118 |
| SO2 Emissions (lbs/MWh) | 0.00 | 0.00 | 0.00 | 0.00 |
| NOx Emissions (lbs/MWh) | 0.05 | 0.05 | 0.05 | 0.05 |
| PM10 Emissions (lbs/MWh) | 0.02 | 0.02 | 0.02 | 0.02 |
| Mercury Emissions (lbs/MMWh) | 0.00 | 0.00 | 0.00 | 0.00 |